Attachment A

Staff Workshop on Amending the California Energy Commission's *Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities*

July 11, 2014

The California Energy Commission plans to amend its regulations, *Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities*, to implement recent legislation. Energy Commission staff also plans to propose revisions to the regulations to address a limited set of additional issues that have been identified since the Energy Commission adopted the regulations in June 2013. Staff will conduct a pre-ruling workshop on July 11, 2014, to discuss proposed amendments and seek stakeholder input. This document is an attachment to the notice of the staff workshop, which is available on the Energy Commission's website at:

www.energy.ca.gov/portfolio/pou_rulemaking/2014-RPS-01/

For this workshop, staff is seeking input from interested parties on the topics presented below. Specifically, parties are encouraged to submit written comments regarding these issues and to respond to the specific related questions, limiting the scope of comments to these topics. Please number your comments to correspond to the numbered topics below, and refer to the workshop notice for details on the process for submitting written comments. There will also be opportunities to provide oral comments during the workshop.

1. Implementation of Senate Bill 591

Senate Bill 591 (Cannella, Chapter 520, Statutes of 2013), was signed into law on October 3, 2013. SB 591 amended Public Utilities Code (PUC) section 399.30 (k) and establishes an RPS exemption for a local publicly-owned electric utility (POU) that receives greater than 50 percent of its annual retail sales from its own hydroelectric generation that is not an eligible renewable energy resource (and that meets other specific criteria), and excuses the POU from having to procure additional eligible renewable energy resources in excess of either:

- the portion of the POU's retail sales not supplied by its own qualifying hydroelectric generation, or
- the POU's adopted cost limitation.

If a POU qualifies for this exemption, the POU is not required to purchase additional eligible renewable energy resources in excess of the procurement requirements of subdivision (c) of PUC section 399.30 (c).

There are two set of issues that the Energy Commission needs to address to implement SB 591. The first set of issues deals with the conditions that allow a POU to qualify for the RPS exemption, and the second deals with the application of the RPS exemption itself.

Satisfying the qualifying conditions for the RPS exemption

The Energy Commission must establish specific conditions that a POU must satisfy to determine if the POU qualifies for the exemption provided by SB 591. Please consider and respond to the following issues and questions.

Issue: An annual demonstration could result in the POU failing to meet the qualifying conditions in dry hydro years, whereas a multi-year average would even out year-to-year fluctuations and make it easier for a POU to satisfy the qualifying conditions for the RPS exemption to apply.

a. How should the 50 percent of retail sales requirement be satisfied? Should a POU have to demonstrate that its qualifying hydroelectric generation[1] supplies enough power each year to meet at least 50percent of the POU's annual retail sales needs? Or should the 50 percent requirement be determined over an average of multiple years, given that hydroelectric generation varies from year to year?

Issue: Section 3204 (a)(7) of the Energy Commission's regulations establishes a seven (7) year averaging period for qualifying hydroelectric generation under PUC section 399.30 (j). Section 3204 (a)(7) also requires a POU meeting the criteria of PUC section 399.30 (j) to submit documentation, within 90 calendars days of the end of each compliance period, on the POU's qualifying hydroelectric generation and electricity demand for the prior seven (7) years.

b. If a multi-year average is used to determine the qualifying conditions for the RPS exemption, over how many years should the qualifying hydroelectric generation be averaged?

c. What should the reporting requirements be for a POU to demonstrate it satisfies the qualifying conditions for the RPS exemption? Should the POU be required to report information to the Energy Commission to demonstrate it satisfies the 50 percent requirement once at the beginning of each compliance periods for its qualifying hydroelectric generation supplies immediately prior to the start of the compliance period?

Application of the RPS Exemption under SB 591

The Energy Commission must determine how to apply the exemption provided by SB 591 to the RPS procurement requirements of a qualifying POU.

a. Assuming a POU satisfies the qualifying conditions for the RPS exemption, should its RPS target be based on its total retail sales or its remaining retail sales not met by its own qualifying hydroelectric generation that is not RPS-eligible? (In either case, the target is not to exceed retail sales not met by its own hydroelectric generation that is not RPS-eligible or the procurement requirements of PUC section 399.30 (c). Please explain your rationale.

[1] For purposes of this document, "qualifying hydroelectric generation" means a POU's own hydroelectric generation that is not an eligible renewable energy resource (and that meets other specific criteria).

b. Should the portfolio balance requirements (maximum Portfolio Content Category 3 and Minimum Portfolio Content Category 1) apply to the POU's procurement toward its RPS target?

c. Should the POU's RPS procurement requirements apply on an annual basis or on a compliance period basis?

d. What should reporting requirements be to verify the RPS exemption is being applied correctly?

2. Portfolio Content Category for POU-Owned or Procured DG System

The Energy Commission is exploring whether generation from an RPS-certified facility consisting of a distributed generation system either owned by a POU or from which the POU procures generation could be classified as Portfolio Content Category (PCC) 1 under PUC section 399.16 (b)(1) and section 3203 of the Energy Commission's regulations for POUs. Is it appropriate for the Energy Commission to classify generation from an RPS-certified DG system as PCC 1 if the DG system is either owned by a POU or the POU procures bundled electricity generation from the DG system? If so, under what conditions? Please consider and respond to the following issues and questions.

Issue: It may be appropriate under the statute and regulations to characterize electricity generation from POU-owned DG systems as PCC 1, because: i) the DG facility is owned by the POU, ii) ownership is synonymous with procurement under PUC section 399.11 (f), iii) the DG system is interconnected to a California Balancing Authority (CBA) or distribution facilities used to serve end user within a CBA, and iv) the POU (as the owner of the DG system) is acquiring both the electricity generation and the associated renewable energy credits (RECs/WREGIS Certificates) from the DG system as a bundled product.

a. Are there circumstances when it would not be appropriate to classify electricity generation from a POU-owned DG system as PCC 1? Would it matter if the electricity generation was immediately sold to a POU customer, rather than transmitted to the POU's distribution system? This could occur where the POU-owned DG systems was located on the customer's site.

Issue: POU-owned DG systems can be distinguished from DG systems owned by a customer or third party to offset the customer's on-site load. When a DG system is owned by the customer or a third party to offset the customer's on-site load, some or all of the electricity generated by the DG system is consumed on-site. Typically, under this scenario only the RECs associated with the generation from the DG system and the net surplus generation from the system is available to be procured by a POU. The RECs associated with the electricity generation consumed on-site would be unbundled and classified as PCC 3, and the RECs associated with the net surplus electricity generation from the system would be characterized as PCC 1. This is consistent with the net-energy metering provisions of PUC section 2827 (h), which provides that an electric utility shall own any RECs for net surplus electricity purchased pursuant to the utility's net surplus electricity compensation rate, and that any RECs associated with electricity generated by the customer-generator and utilized by the customer-generator shall remain the property of the customer-generator.

b. Under what circumstances, if at all, would it be appropriate to classify electricity generation from a customer-owned or third party-owned DG system as PCC 1, when that electricity generation is used to meet the customer's on-site load?

c. Would it be appropriate for a POU to procure all of the bundled electricity generated by a customer-owned DG system and then immediately sell back to the customer all of the commodity electricity to serve the customer's on-site electrical load and claim the procurement as PCC 1? Could such a transaction comport with section 3203 (a)(1) of the Energy Commission's regulations that precludes a POU from buying a bundled electricity product and then reselling the underlying electricity from the bundled product back to generator from which the electricity product was purchased?

d. If the customer installed the DG system to offset the customer's on-site load, and the system is being operated for this purpose, is the system's electricity generation available to be procured by a POU? How would the generation under such a transaction compare with generation from a central station facility that uses a portion of the facility's generation to satisfy on-site load, and sells the facility's net surplus generation to a utility via a power purchase agreement? An example of a central station facility could be a biomass facility that uses a portion of the facility's electricity generation to meet the on-site electrical load of related timber milling operations. How would your response differ, if at all, if a third party owned and installed the system?

e. How, if at all, would the net-energy metering provisions of PUC section 2827 be implicated if a POU were to procure all of the bundled electricity generated by a customer-owned DG system and then immediately sell back to the customer all of the commodity electricity to serve the customer's on-site electrical load?

3. Definition of "retail sales"

The Energy Commission is considering whether the current definition of "retail sales" should be clarified in section 3201 (bb) of the Energy Commission's regulations for POUs. Please consider and respond to the following issue and questions.

Issue: Based on conversations with POU representatives, it is not clear that POUs are determining their "retail sales" in the same manner. For example, some POUs may be excluding electricity demand from other departments, units, or enterprises within the municipality, while other POUs may not be doing so. It may be difficult for a POU to determine where to draw the line between the POU/municipality's consumptive demand and "retail sales," particularly if the POU serves related, but separate entities within or associated with the municipality, such as enterprise zones or joint powers authorities.

a. Does the definition of "retail sales" need be to clarified to ensure POUs are properly excluding their consumptive loads in determining retail sales?

b. If clarifications are needed, how should the definition of "retail sales" be revised to properly exclude a POU's own consumptive demand, but capture all sales to its retail customers?

4. Definition of "resale"

The Energy Commission is considering whether "resale" should be defined in the Energy Commission's regulations for POUs. Please respond to the following question.

a. The Frequently Asked Questions posted on our website includes the following definition of resale: A purchase is considered a "resale" if the POU is buying the electricity product from another California RPS-obligated utility.

b. Is this guidance sufficient or is additional guidance needed, and if so in what areas and why?

5. Contract Amendments and Excess Procurement

The Energy Commission is seeking input on whether the Energy Commission's regulations for POUs should address subtraction of short term contracts for purposes of excess procurement. Please consider and respond to the following issue and question.

Issue: Section 3206 (a)(1)(A) of the Energy Commission's regulations requires that electricity products procured under contracts of less than 10 years in duration be subtracted from the calculation of excess procurement, unless the electricity product is deemed "count in full." However, the regulations do not currently address how the term of the contract is calculated when the original contract term is amended. For example, if the term of the original contract is 7 years, and the contract is amended shortly before it ends to add an additional 5 years, should the term of the contract now be considered 12- years for purposes of calculating and subtracting excess procurement or should the 5-year addition be considered the term for calculating and subtracting excess procurement, since the duration of time from the amendment date to the end of the original contract is less than 10 years.

a. Should the regulations be clarified regarding the term of amended contracts for purposes of calculating and subtracting excess procurement? If so, how and why?

6. Dynamic Transfer Agreements

The Energy Commission is seeking input on whether its regulations for POUs should further clarify the definition of "dynamic transfer agreements" for PCC 1 in section 3203(a)(1)(D). Please consider and respond to the following issue and question.

Issue: PUC section 399.16 (b)(1)(B) states that PCC 1 can be electricity products that "have an agreement to dynamically transfer electricity to a California balancing authority." Dynamic Transfers fall into two categories: 1) pseudo tie and 2) dynamic schedule. There may be more assurances with pseudo tie facilities that the electricity is scheduled into a CBA consistent with requirements for other PCC 1 electricity products. Electricity from facilities that are dynamically scheduled may not necessarily be scheduled into a CBA. Consequently, the electricity from pseudo tie facilities may more closely resemble other electricity products in PCC 1.

The Energy Commission's regulations currently only require an agreement to verify dynamic transfer.

a. Do the regulations need to distinguish between a facility's generation under a "pseudo tie" agreement and a facility's generation under an agreement wherein the electricity is "dynamically scheduled"? If so, should the Energy Commission consider hourly verification of deliveries under dynamic scheduling agreements for PCC 1?